ATTACHMENT A

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development.	Rulemaking 01-10-024 (Filed October 25, 2001)
Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning.	Rulemaking 04-04-003 (Filed April 1, 2004)

WORKSHOP REPORT ON RESOURCE ADEQUACY ISSUES

Prepared by:
Michelle Cooke
Administrative Law Judge

June 15, 2004

TABLE OF CONTENTS

1 Procedural Background

This Workshop Report is submitted consistent with the February 13, 2004 ALJ Ruling in R.01-10-024. Administrative Law Judge Michelle Cooke facilitated a series of workshops that were held on March 16, April 6, April 7, April 12, April 13, April 14, April 26, May 5, May 17, May 18, and May 26.

The workshops focused on how compliance by load-serving entities (LSEs) with the 90% year-ahead forward commitment requirement adopted in D.04-01-050 will be assessed. Topics covered included protocols for counting supply and demand resources, deliverability of resources to load, and load forecasting.

The purpose of this report is to identify consensus agreements reached by the workshop participants, identify issues where agreement does not exist and set forth options to resolve those issues whenever possible.[1]

Some issues that are very important to establishing clear rules for assessing resource adequacy were not tackled, for example, penalties in the event of non-compliance and rules for transitioning from year-ahead resource adequacy compliance to operations. These issues still require additional work by the parties and guidance by the Commission, but the Commission must make certain threshold decisions regarding the scope and structure of the year-ahead 90% forward commitment requirement and showing to make discussion of the topics that were set aside fruitful.

---

[1] Throughout the course of the workshops, many parties prepared straw proposals for discussion purposes. Some, but not all, of these materials are included in the workshop report when the document provides a helpful summary of the issues, reflects consensus discussions, or is fairly technical in nature. Inclusion or exclusion of a particular document should not be taken as any indication of approval of any position expressed in the document, but rather a judgment by the workshop moderator on whether inclusion of the document in the workshop report added additional information necessary for the Commission to decide the issues before it.

reporting process for resource adequacy. **The parties strongly urged that the 90% year-ahead forward commitment showing NOT include the assessment of the reasonableness of actual procurement decisions by LSEs but that determination of reasonableness should be known in advance of making the year-ahead showing.**

The implication of this general agreement is that the amount of load an LSE is responsible for serving must be known early on so that study work relating to deliverability (especially of imports) can be completed in advance of procurement and the year-ahead showing. The work group focusing on load forecasting issues recommended that:

> Each LSE should provide a forecast of its hourly loads for each of the five summer months early each year (somewhere between January and April) for the period May-September of the next year (e.g submission in 2005 for loads during May-September 2006). If there were to be review and/or reconciliation adjustments of a draft load forecast before it was finalized ... the draft would come early in each calendar year, and adjustments would take place through the end of March with a goal of load forecasts finalized by April (e.g by April 2005 for the projected loads May-September 2006).

Finalization of each LSE's allocation of load is a necessary precursor to analysis of deliverability and procurement.[3] At the workshops, the California Independent System Operator (CAISO) stated that it would be able to perform its deliverability analysis in two months.[4] Following the deliverability assessment, sufficient time would be required for LSEs to procure resources (and potentially receive approval of them) to meet their load obligations, prior to making the year-ahead resource adequacy showing.

---

[3] At the workshop, the discussion appeared to assume that the CEC would review forecasts and perform any necessary reconciliation or allocation, although no statement of agreement occurred regarding this responsibility. (See Section 4 below.)

[4] This projection is for the second year the analysis is performed. The CAISO assumes that the first year analysis and development of baseline assumptions will take at least six months to complete. See discussion of Deliverability (Section 6 below) for more discussion of the analysis and data requirements.

Because of the uncertainty of the procurement approval process, it was not possible for parties to reach agreement on the timing of filings and the workshop moderator decided that discussion of reporting requirements related to resource adequacy should not occur until further guidance was provided.

The Commission must decide whether the resource adequacy showing follows the procurement approval process or incorporates an assessment of the reasonableness of procurement decisions into the resource adequacy showing. Given that decision, *the Commission must decide when an LSE must demonstrate that it has met the 90% year-ahead resource adequacy requirement.* At that point, it could be useful to have a working session to discuss the elements of the resource adequacy showing.

3 Phase-In

D.04-01-050 adopted a planning reserve margin (PRM) of 15-17% to be achieved no later than January 1, 2008. The planning reserve margin incorporates a 7% operating reserve margin required by Western Electricity Coordinating Council (WECC). The phase-in of the adopted planning reserve margin was not decided and instead was reserved to the workshops. The year-ahead 90% forward commitment requirement is applied to the load forecast plus planning reserve margin so the phase in affects the amount of reserves and forward commitment an LSE must make. Consistent with Finding of Fact 19 of D.04-01-050, this year-ahead requirement is to be implemented in 2007. For example:

90% applies for 2008 load plus applicable reserves, showing in 2007
90% applies for 2009 load plus applicable reserves, showing in 2008

Parties generally agreed that LSEs should make a year-ahead 90% forward commitment showing beginning in 2005 for the May through September 2006 load forecast but parties were unwilling to agree that the year-ahead 90%

The parties discussed the pros and cons of this approach. The approach is simple to implement, fits with any target date for compliance, and assuming the January 1, 2008 compliance date remains, the resulting phase-in allows building new generation to be an option for meeting the requirement, which can mitigate market power. On the other hand, at least one party is concerned that the current year planning reserve margin component of the formula is not clear.[7]

3.2 Fast Phase-In

The fast phase-in is not so much a phase-in recommendation as a recommendation to modify the target compliance date. This approach is recommended by parties who want LSEs to meet the 15-17% target sooner rather than later. These parties recommend that LSEs be required to acquire a reserve margin of no less than 10-12% in 2005 and 15-17% in 2006. The CAISO, in particular, advocates this approach because of its concern that the May through September period typically has a 3-12% generation forced outage rate and with a longer phase-in, this forced outage rate could result in insufficient reserves to maintain the required 7% operating reserve margin. Some parties argue that the record in R.01-10-024 found that there was a generation surplus, therefore meeting this higher standard should not be problematic. Others believe that a faster phase-in is most consistent with the administration's policies and will encourage implementation of demand response programs. Some parties believe that adoption of a faster phase-in will encourage building of new resources and existing unit staying online; others believe that building new resources is eliminated as an option with this phase-in and existing units will hold significant

---

[7] The workshop moderator believes that this lack of clarity stems from the fact that LSE's have identified their short-term reserve requirement goals in other procurement filings, but no goal is adopted for 2004 or 2005 for the required

section of the report assumes that some type of assignment of load responsibility or reconciliation occurs[8] so that an LSE will know clearly what its resource adequacy requirements will be in advance of the resource adequacy showing.

The parties did not reach agreement on whether load reductions associated with demand response programs are to be removed from the load forecast or treated as a resource. This issue is discussed in Section 5.6.2 below.

4.1 Load Information Each LSE Must Submit

The load forecasting working group reached agreement that each LSE must submit hourly loads for each of the specified five summer months (May-September). This level of data is necessary to allow for adjustment for coincidence should the Commission decide such an adjustment is appropriate (see below). The parties support this recommendation.

Load forecasts need to include sufficient documentation to permit the reviewing entity to assess the results and basic forecasting approach. The load forecasting working group recommended that the following items be required:

- Historic hourly load for the previous year as used in CAISO settlement processes, adjusted for weather using an agreed-upon adjustment methodology
- Hourly values of the Load Forecast
- Basic documentation of customer counts[9], methodology, program impacts included (energy efficiency, distributed generation, price responsive demand, etc.)

---

[8] The parties did not agree upon who should perform this assignment, but the CEC and CAISO were both mentioned as potential independent entities who could perform this assignment/reconciliation.

[9] Energy Service Providers (ESP) believe aggregate counts of customers should be sufficient to satisfy this requirement.

4.2.1 Coincidence Analysis

The load forecasting working group proposed two methods for assessing coincidence: LSE submitted forecast and historical loads (adjusted to average weather). Both are described in detail in Appendix B, with pros and cons of each method identified.[11] At the workshop the parties discussed both methodologies, but did not reach agreement on which way was preferred. Under the LSE submitted forecast approach, the designated load for the 90% forward commitment requirement is based on each LSE's share of total load during the CAISO's coincident peak hours, rather than LSE loads on their individual peak days. Under the historical loads approach, a coincidence adjustment is derived from the LSE's load at the time of the monthly CAISO peak, relative to the LSE's own monthly peak. Parties pointed out that if LSE submitted forecasts are used, all LSEs need to use the same modeling approach. One party was concerned that it is unclear whether hourly summer loads can be weather normalized.

The Commission need not adopt the specific implementation method laid out in Appendix , but *must decide whether coincidence analysis should utilize LSE submitted forecasts or historical loads.* In addition, *the Commission must decide whether any supplemental analysis needs to be performed for purposes of identifying the forward obligation for resource adequacy purposes.*

4.2.2 Should Forecasts (and Resource Adequacy Obligations) be Adjusted for Non-Coincidence?

The parties estimate that if no adjustment for non-coincidence occurs, approximately 1000-2000 MW of additional resources, above that needed to meet

---

no longer confidential and such "higher level" results can be prepared and released by the reviewing entity(s). No discussion of at what level of load aggregation shifts from confidential to public has yet taken place.

[11] Appendix B also describes a supplemental analysis that could provide additional information to assist in interpreting the results of the analysis. Some parties supported performing the supplemental analysis but others believe it is a very difficult analysis to perform.

south or south-north at peak, it would be important for each LSE to carry full reserves for their load, rather than relying on system coverage for peak loads.

The Commission must decide whether the load forecasts that set the resource adequacy 90% forward commitment obligation should be modified based on coincidence analysis. In addition, *it would be useful for the Commission to identify whether it is willing to have another entity, and if so, which one, perform the coincidence analysis and modification to load forecasts based on the coincidence analysis.*

4.3 Assignment of Load Responsibility to LSEs

The most crucial load forecasting concern is that the load of EVERY customer (including new customer growth) is assigned to be the responsibility of some load serving entity, otherwise resource adequacy objectives will not be met. The question is what customer base establishes the amount of load each LSE is responsible for procuring resources for, to meet its 90% forward commitment requirement. The fundamental problem that the choice of customer base raises is the relationship between the forecast and the financial obligation that comes with being resource adequate and the fact that load can move between LSEs between when the forecast occurs, the resource adequacy showing is made, and real time.

Two primary methodologies were proposed to assign load responsibility to LSEs: Current Customer and Best Estimate. These two methodologies are described in detail (along with pros and cons) in Appendix B, the Load Forecasting Strawperson. At the workshop, three other methodologies were also discussed: rolling 12-month forecast, IOU total service territory with allocation by a non-LSE, and only contracted amounts for non-IOU LSE.

Several parties expressed significant concerns that if methods other than the current customer methodology are used, there is a significant problem with

The Commission must decide which approach to forecasting customer base and assignment of load to LSEs it prefers. In addition, *it would be useful for the Commission to identify whether it is willing to have another entity, and if so, which one, perform this assignment and reconciliation of load.*

4.4 Inclusion of Losses in Load Forecasts

At the workshop parties discussed how to reflect transmission losses and unaccounted for energy (UFE) for purposes of determining the amount of load that establishes the resource adequacy requirement. The CAISO estimates that system-wide transmission losses could be in the range of 2000 MW, so accounting for these losses has important cost implications for LSEs. The CEC estimates that UFE could be in the range of -1 to +2% of metered load. The point on the electric system at which load is defined for purposes of establishing each LSE's load forecast impacts whether transmission losses or UFE are included in the forecast and thus whether an LSE must carry reserves for that load. Two different points of measurement were identified: CAISO interface and generation busbar.

Conceptually, load at the generation busbar is greater than the load measured at the CAISO interface by the amount of physical transmission losses between the generators and the CAISO interface, which is commonly referred to as a "transmission loss factor". SCE has found that, in practice, this "transmission loss factor" has to account for more than just the physical losses, for example UFE and metering discrepancies between real-time energy management systems and billing meters used for settlement.

For CAISO settlement purposes, LSEs currently use end-use metered usage plus losses up to the CAISO-interface. This measure represents hourly done. At least one party is concerned that if load forecasts are determined at generation busbar, the assignment of responsibility to procure to cover transmission losses to non- CPUC jurisdictional LSEs (i.e., municipal utilities) is necessary but problematic.

Some parties believe that transmission losses will already be accounted for in the determination of "qualifying capacity" for counting (see Section 5 below), and thus inclusion of losses by determining load generation busbar will result in double procurement of capacity representing losses. Parties appeared to agree that if the qualifying capacity of generating resources reflects a reduction for transmission losses, then transmission losses do not also need to be reflected in the load forecast. Parties also appeared to agree that UFE associated with energy theft is load that LSEs need to acquire resources (including reserves) to cover.

The Commission needs to decide whether transmission losses should be reflected in the load forecast by defining an LSE's load at the generation busbar or whether transmission losses should be reflected in the generation counting protocols. If the Commission decides instead that load should be defined at the CAISO interface then it should direct LSEs to adjust their load forecast for UFE and reduce generation qualifying capacity to reflect transmission losses.

4.5 Inclusion of Energy Efficiency Savings in Load Forecast

Parties agree that committed energy efficiency savings should be forecast and documented by each LSE in their load forecasts. For an energy efficiency program to be considered committed, **parties agreed that it must either have authorized funding (by a regulatory body) or a customer contract or commitment to the program. Parties agreed that a minimum level of**

eligible to be counted for meeting the resource adequacy requirement, prior to assessing deliverability of the resource. Establishing qualifying capacity is the first step in determining a given resource's contribution towards meeting the year-ahead resource adequacy requirement of a load-serving entity.

The parties agreed on formulas for calculating qualifying capacity for numerous types of resources as described below. However, parties could not agree on whether qualifying capacity for unit specific resources owned or controlled by load-serving entities should be reduced for unit specific forced outage (FO) rates. *The parties agree that the Commission should decide whether a unit specific forced outage rate should be included in the qualifying capacity formula and therefore included a placeholder in the formula in the event that the Commission decides such an adjustment is appropriate.* More discussion on the forced outage adjustment follows the qualifying capacity formulas/protocols table.

The parties agreed that the North American Electric Reliability Council (NERC) Generating Availability Data System (GADS) definitions of industry terms should be relied upon in determining qualifying capacity. This set of definitions is attached as Appendix C. The following terms from the NERC GADS definitions are used in the formulas:

NDC= Net Dependable Capacity

SO= Scheduled Outages

Once a term is defined, it is not redefined each time it is used in a formula.

Resource Type	Agreed upon Formulas/Protocols (continued)
Group B: Existing Qualifying Facility Contracts- See Qualifying Capacity Formulas for Existing Qualifying Facility Contracts below	
Group C: Contracts[13] - See Contracts discussion below	
Unit Specific Contracts	
Contract tied to physical plant characteristics	QC defined as specified for Group A
Contract for specific output	QC defined as specified for Group B
DWR Contracts: No Agreement- See DWR Contracts below	
System Contracts	
Imports[14]	QC= Contract Amount provided the contract: 1. Is an Import Energy Product with operating reserves 2. Cannot be curtailed for economic reasons 3a. Is delivered on transmission that cannot be curtailed in operating hours for economic reasons or bumped by higher priority transmission OR 3b. Specifies firm delivery point (not seller's choice)
System	No agreement- See Intra-Control Area System Sales below
Reliability Must Run Contracts, Condition 2	QC defined as specified for Group A and allocated to Participating Transmission Owners/LSE's based on their paid share of uplift costs.
Curtailable	QC = zero[15]

[13] Parties agreed that inclusion of a provision in the contract that allows for interruption to serve the seller's native load, in the context of a force majeure situation, does not automatically exclude the contract for counting towards the resource adequacy requirement.

[14] The CAISO expressed concern that this requirement would still allow for the seller to curtail its deliveries to meet native load requirements. The CAISO stated that it needs to research what triggers the right to curtail to meet native load, and depending on the outcome of that research, they could agree to the definition for import contracts to count. In addition, the CAISO indicated that it is concerned that WSPP Schedule C has an element that allows substitution of financial payment for failure to deliver. The CAISO indicated it needed to do more research on whether WSPP Schedule C would meet the definition of "economic reasons" before agreeing to this definition for import contracts to count.

[15] Parties agree that contracts that are curtailable for economic reasons (e.g., spot energy and capacity) should not count towards meeting the 90% forward contracting requirement. For this reason, the workshops did not address the availability of spot market energy and capacity. The workshop moderator believes that the issue of availability of spot market energy and capacity could better be addressed in the context of long term planning objectives and evaluation of whether the 90% forward contracting requirement is too high or too low given the availability of spot market energy and capacity.

arises out of concern for equitable treatment between qualifying (QF) contracts and other resources. Some parties argue that the adopted 115% planning reserve margin reflects historical forced outage rates for LSE owned/controlled resources. These parties believe that incorporating a forced outage factor into the QC formula would result in over-procurement of resources and higher costs to ratepayers. These parties believe that if a forced outage factor is reflected in the QC for LSE owned/controlled resources, then the 115% planning reserve margin should be revisited. These parties believe that the nature of QF contracts ("put" contracts as opposed to "call" contracts of LSE owned/controlled resources) requires incorporation of historical performance in the QF contract QC, rather than just relying on contract capacity to set QC.

Other parties believe that if historical performance is reflected for some resources, it should be reflected for all resources. These parties believe that incorporating historical performance and forced outage factors on a unit specific basis would result in stronger incentives for unit owners to ensure performance on peak, reward units that do perform consistently on peak, and reflect the true availability of units that fail to perform on peak. This approach would require some entity to collect forced outage data.

Parties agree that QF historical performance data does capture forced outages, unlike the calculation of QC for LSE owned/controlled resources if no forced outage factor is incorporated. Parties agree that a potential solution to this situation is to "gross-up" the QF historical performance rate by 1/(1-FO). However, it is unclear whether forced outage rates for QF units would be readily

---

[18] Parties agreed in concept that projects under construction should be counted but did not reach agreement on when they should begin to count. The issues surrounding the timing of counting resources under construction is discussed

load exceeded 90% of the monthly system peak, rounded to the nearest ten. The CAISO agreed to perform this calculation, which is set forth below.

Number Hours ISO Load Greater than 90% of the Monthly Peak

	May	June	July	August	September	Total
1998	-	78	39	52	29	198
1999	21	11	20	36	38	126
2000	20	80	25	67	23	215
2001	50	46	27	62	43	228
2002	27	28	45	56	38	194
2003	10	18	106	75	56	265
Avg. Hours	26	44	44	58	38	210
RA Obligation	30	40	40	60	40	210

The parties also agreed that individual energy limited units that meet the hours/days requirement can add together to meet the monthly hours obligation so that they may be counted for that number of hours in the resource adequacy showing. In addition, the parties agreed that each monthly hours requirement is independent from other months. This means that an LSE may designate an energy-limited resource to count for the month of August, but not May (for example).[19] *The Commission must decide whether this minimum hours requirement agreed upon by the parties for energy limited resources is acceptable.*

5.3 Qualifying Capacity Formulas for Existing Qualifying Facility Contracts

Parties at the workshop generally agreed that historical performance at peak should be considered in determining QF qualifying capacity, however, one party raised equity concerns because historical performance data captures forced outages for QFs, which is not captured by the formulas agreed upon for Group A resources if the forced outage rate is excluded. *It is the workshop moderator's belief*

---

[19] These requirements are only for supply resources, demand response programs with limitations on their use are addressed in Section 5.6.1 below.

different performance of old and new wind projects and differences in performance between geographic regions. Those who support Option 1 believe that looking at past production best captures these performance differences. These parties also point out that we would need to understand how the ELCC is calculated to ensure that it assesses load-carrying capability for the time period that is relevant for resource adequacy purposes, not for some other time period. Those who support Option 2 fear that Option 1 will undervalue capacity of new wind resources.

The Commission must decide which of the options for solar (without gas backup) and wind resources to adopt, and whether to adopt the formulas proposed for Existing Qualifying Facility Contracts in light of its decision on forced outages.

5.4 DWR Contracts

Finding of Fact 22 of D.04-01-050 states: "California should receive full credit and value for the long-term contracts entered into by the DWR to help California meet its energy needs during the crisis." The term "full credit and value" was not defined in the decision and the issue of how to count these contracts was referred to workshop. The parties did not reach agreement on how to ensure that full credit and value for these contracts is given.

The 9670 MW of DWR contracts consist of 3 types of contracts: unit specific resources (4095 MW); portfolio of resources (2600 MW)[26]; and market resources (2975 MW).[27] There are two parts to assessing whether (and how much of) a contract can be relied by an LSE in meeting its year-ahead 90% forward

---

[25] Peak hours were not defined.

[26] Portfolio of resources contracts have multiple generation units identified that the contract holder can use to meet its contract obligations.

[27] These figures are for contracted capacity in 2008.

The Commission must provide its definition of full credit and value of DWR contracts so that LSEs know how they can rely on the DWR contracts in the year-ahead showing.

5.5 Contracts

Parties agreed that to evaluate contracts there are several threshold questions that need to be addressed, and the answers affect how a given contract should count towards meeting the year-ahead resource adequacy requirements. At the April 7, 2004 workshop parties developed a set of yes/no questions that depending on the answers, could result in a contract qualifying for inclusion in an LSE's portfolio for year-ahead resource adequacy purposes. In essence, contracts were divided into two types: those backed by physical capacity or demonstrable rights to physical capacity, and financial products not backed by physical capacity or demonstrable rights to physical capacity. Parties were able to agree on definitions of qualifying capacity for contracts backed by physical capacity (as reflected in the protocol table) but were unable to agree on what constitutes "demonstrable rights to physical capacity" and thus were unable to clearly identify whether certain types of contracts meet this test and constitute qualifying capacity.

The contracts that raise the most questions about whether they can be considered to hold demonstrable rights to physical capacity are system import contracts (primarily from the Pacific Northwest) and intra-control area system sales. **The parties discussed the import contracts and were able to reach an agreement on the elements that a contract must have to constitute qualifying capacity, subject to additional research by the CAISO.** That agreement is reflected in the protocol table. The parties discussed intra-control area system

Commission consider allowing some limited percentage of the year-ahead portfolio to be this type of contract, until a more tradable product backed by physical resources is available in the market. Workshop participants indicated that they would continue to work to find common ground on the issue after the workshops concluded.

The Commission must decide whether intra-control area system sales constitute qualifying capacity for purposes of the year-ahead resource adequacy showing.

5.6 Estimating Load Reductions from Demand Response Programs

There are several types of demand response programs:

- Reliability/Emergency Programs: air-conditioner cycling programs; Interruptible tariffs
    - Utility cycling programs include direct control by the utility over whether customer interrupts
    - Utility interruptible tariffs all have different eligibility, triggering conditions, curtailment provisions, penalty provisions, operational history and do not include direct control by the utility over whether customer interrupts
- Price Responsive Demand Programs: Dispatchable programs; non-dispatchable programs
    - Dispatchable program provisions include a trigger price/event which alerts the customer the program is being "called" or dispatched

existing demand response programs can be triggered for periods of time less than four hours a day and have limitations on the number of hours they can be called in a month (or days in a row) that do not meet the criteria established for energy limited generation resources. **Parties agree that demand response programs need to be available for 48 hours over the May-September season to be able to be relied on in the year-ahead showing.**

The parties discussed two options for how demand resources could be relied on in the year-ahead showing:

1. All MW signed up for demand response programs with at least two hours/day availability count, provided that they meet the 48 hour/season criteria.
2. MWs signed up for two hour demand response programs need to sum to four hours per day to count (i.e., 200 MWs of 2 hour/day load reduction = 100 MW for resource adequacy counting) plus sum to monthly requirement described for energy limited resources and 48 hours/season.

Parties that support the first option argue that the load duration curve is needle-like at its peak and that programs with two-hour limits on availability should be able to meet that needle peak and count without being discounted because they cannot meet a four-hour peak or meet the monthly requirement set for energy limited generation resources. These parties are concerned that if programs that are available only for two hours cannot be utilized for resource adequacy requirements, programs may need to be redesigned because additional resources will be needed to satisfy resource adequacy requirements and the economics of the demand response programs will be impacted. Those who demand response resources must be available for more than two hours to be used in the year-ahead showing, *the Commission must decide what minimum hourly and/or monthly availability requirements must be met.*

5.6.2 Should Demand Response Programs Be Treated as Demand Reduction or Supply for the Resource Adequacy Showing?

The Commission must decide whether demand response programs (interruptibles, direct load control, and price responsive demand) are treated as a demand reduction or supply resource for purposes of assessing resource adequacy. The primary implication of this decision is whether an LSE must carry (and procure) reserves for the capacity associated with demand response programs. The utilities argue that they do not now, and never have, carried reserves for the load signed up under interruptible programs, precisely because customers on these programs can be interrupted. Those who advocate for treating these programs as supply resources are not so concerned with the reserves question, but rather with the difficulty of how you might model interruptible programs as a demand reduction and the fact that interruptibles are called in a manner more like a supply resource.

Parties discussed three options for how to treat demand response programs: (1) treat dispatchable programs as supply resources, non-dispatchable programs as load reductions; (2) remove all demand response programs from the load forecast; (3) treat all demand response programs as supply resources.

Parties that support handling programs based on their dispatchability argue that dispatchable programs operate much more like an energy limited product and because of these operating characteristics, it is hard to consider it a load forecast reduction comparable to an energy efficiency investment. At least one party felt that it was worth discussing eliminating the need to carry reserves decides dispatchable programs should be treated as supply, *it must decide whether reserves must be carried on that amount of load reduction.*

5.7 Timing of When to Count Resources Under Construction

The issue of when you can count resources under construction is driven by the fact that the resource adequacy showing is made the year-ahead and there is considerable uncertainty as to whether projected online dates of projects are realistic. The CEC website shows an expected online date and a percentage constructed for all projects sited by the CEC at http://energy.ca.gov/sitingcases/all_projects.html. The parties discussed the calculation approach and reliability of the data included in that list and decided that at this point in time, it should not be relied upon for counting purposes. Instead, the parties discussed, but did not agree upon, three options for when a resource should be able to be counted:

Option 1: the scheduled commercial operation date
Option 2: 30 days after scheduled commercial operation date
Option 3: 90-120 days after scheduled commercial operation date

Some parties are concerned that the scheduled commercial operation date that would be known a year in advance is not sufficiently robust to ensure that an LSE will be resource adequate in real time. Parties that advocate for Option 1 believe that the scheduled commercial operation date can be used if there are penalties for an LSE that is not resource adequate in real time. These parties believe that if penalties are in place, LSEs will incorporate provisions into contracts with new generators to make the online date more reliable. Parties that advocate for Option 3 believe that many new projects do not actually come online until a few months after the scheduled commercial operation date known

6.1 Baseline Analysis of Deliverability of Resources to CAISO Control Area and Aggregate of Load

The parties agree that the CAISO should conduct the baseline deliverability analysis that establishes the deliverability of imports to the CAISO control area and deliverability of resources to the aggregate of load.

Appendix D was prepared for discussion purposes at the April 12 and 13, 2004 workshops and contains more technical details about the CAISO's proposed evaluation methodology than described herein; it was used to identify concerns that parties had about specific methodologies.[34] At the April 12 and 13, 2004 workshops, the parties concluded that additional technical work related to assessing import capacity would be useful. Appendix E describes a baseline analysis that the CAISO would perform to establish an amount of total import capacity available at each intertie.[35]

In a nutshell, the CAISO would establish an initial level of total import capacity available at each intertie based on historical 2003 on-peak summer import levels. The CAISO would then review the impact of that level of imports on the deliverability of generation internal to the CAISO control area (deliverability to aggregate of load) and adjust the import capacity level down if the deliverability of internal generation is impaired by the initial import assumption, no upward adjustment to the capacity import level would be made above historic levels.

---

[34] The subjects in Attachments 1 and 2 of Appendix D were discussed at the workshops, the merits of Attachment 3 were not discussed because parties could not agree whether it was necessary to test deliverability of resources to transmission constrained areas. see Section 6.4.

[35] The approach described in Appendix E was discussed at the May 5, 2004 workshop.

- Dry hydro vs. normal hydro assumptions

Despite the lack of agreement over whether certain information is needed, the workshop moderator does not believe that the Commission needs to resolve any issues with respect to data at this time. Instead, the parties should work with the CAISO during the first baseline analysis to refine the data requirements and information that each LSE must provide to the CAISO.

6.2 How Should "Deliverability" be Allocated to Existing Resources if Deliverability to Aggregate of Load is Constrained?

In assessing the deliverability of a generation resource to aggregate load, the intent is that the deliverability assessment will be consistent with the deliverability finding and requirements that stem from the interconnection process.[36] The result is that as generators come online, their deliverability to the aggregate of load is assessed and, if there are deliverability issues, the generator is offered upgrade options to make their resource fully deliverable. **Parties agreed that it makes sense for a generator to be pre-certified as to their deliverability. Parties agreed that new generation coming online would not result in a change to an existing generator's rating for deliverability. Parties agreed that a generator that commits, through the interconnection process, to pay for upgrades to make it deliverable would pass the deliverability screen up to that level. Parties also agreed that deliverability is a sliding scale,** in other words, a generator with a 100 MW QC may only be able to deliver 80 MW to the aggregate of load under the baseline deliverability scenario. Under this example, unless the generator pays to upgrade the transmission system, the

---

[36] Parties agree that because the interconnection process is overseen by FERC, the entity that performs the interconnection deliverability study will be decided by FERC.

system upgrades, planning to meet resource adequacy is made more difficult and impacts the willingness of developers to invest in California resources. This is why in the discussion above, parties agreed that a resource should be pre-certified as to its deliverability. *Any guidance the Commission can provide as to whether, and if so, how, deliverability of resources should be derated due to general system conditions will help provide certainty and investment direction.*

6.2.1 Allocation Based on Payment for Firm Transmission

Under this approach, rather than perform a pro-rata allocation to all generators if a constraint exists, capacity would first be allocated to generators who paid for firm transmission upgrades to make them deliverable[37] or who did not need to add transmission capacity to be deliverable as set forth in their interconnection study. At the time of interconnection a generator has the option to pay for upgrades to accommodate all or part of its output. The objective is that those generators that paid for deliverability for any or all of their output (or did not require upgrades at time of interconnection to be deliverable) would also be deliverable to that same extent for purposes of the resource adequacy showing. If additional transmission capacity is available, then it would be allocated to those generators for whom transmission needs were identified but who elected not to pay for upgrades at the time of interconnection.

Under this approach the amount of qualifying capacity of a generator who did not pay for firm transmission would be derated until those generators that had paid for firm transmission were deliverable. The percentage a particular generator's qualifying capacity was derated would set that generator's

---

[37]Historical utility resource plans on file with the Commission were suggested as a data source for determining firm resources prior to the existence of the CAISO. Once the CAISO came into existence, interconnection studies would be the data source for determining how firm a generator's transmission is.

Parties agree that the CAISO should identify the total capacity over each intertie and allocate it to each LSE (consistent with the approach adopted by the Commission) **approximately six months in advance of the year-ahead showing.** The parties agree that the LSE is limited to assuming that allocation in its resource adequacy showing, but it must have a contract utilizing its allocation for the capacity to have value in the resource adequacy showing. Parties point out that with the ability to trade the allocation of intertie capacity, there would be less unused capacity. *The Commission must decide if intertie capacity allocated to a particular LSE can be traded to another LSE and be able to count for resource adequacy purposes for the second LSE.*

Parties did not agree on the duration of the allocation of intertie capacity to LSEs, but discussed the possibility of using a one year allocation, a three year allocation, or the duration of the contract or resource that relies on the intertie to set the duration of the allocation of intertie capacity.[38] The duration of the allocation impacts the ease of determining transfer capability and predictability. There is a tension between updating allocations to LSEs and adopting a longer term predictable duration of the allocation. Those who support a one year allocation argue that it is inefficient to sign longer term contracts to use the allocation because of mobility of load and that LSEs without historical use of the intertie will not be able to get an allocation. Those supporting a duration longer than one year argue that it results in greater surety for resources that LSEs contract with that they will assist in the resource adequacy showing and that a

[38] This discussion occurred at the April 12 and 13, 2004 workshops. At the May 5, 2004 workshop, the parties appeared to agree that once an allocation is made and is being utilized, that capacity does not need to be reallocated in subsequent years, as long as the contract using that path still exists. Because of the difference in discussion between the two workshops, the workshop report covers the discussion, assuming the dispute still exists, but parties should comment on whether the discussion at the May 5, 2004 workshop resolved this issue.

and then put all capacity up for bid, with the revenue from the independently administered auction flowing back to LSEs based on the rights they hold under the initial allocation.

Parties did reach agreement that, if a pro-rata approach is used for the initial allocation or allocation of remaining capacity, then LSEs should receive an initial proportional allocation for the load they serve based on their contribution to revenue requirement rather than on access charges as described in Appendix F. The pro-rata allocation would use either historical or forecast load data, consistent with the approach adopted for determining the load forecast in Section 4.3 above.

The ability to trade rights to an import capacity allocation in a secondary market, whatever the initial allocation methodology adopted, should assist in addressing some of the concerns that assigning rights based on existing commitments or contracts limits the ability to enter into new contracts that require the use of the interties.

The Commission must decide how to allocate import capacity to LSEs for purposes of the year-ahead resource adequacy showing.

6.4 Is there a Resource Adequacy Requirement in Load Pockets?

The CAISO proposed that a third deliverability screen be adopted to assess a resource's deliverability to transmission-constrained areas, also called load pockets. A load pocket is a particular area of load with insufficient transmission to cover its load requirements, for example, the San Francisco Peninsula. Some parties support the concept of a load pocket deliverability requirement; other solutions as well. These parties argue that if a load pocket procurement requirement is adopted, reliance on reliability must run units and must offer calls should be reduced. One party specifically suggests that LSEs serving load in pre-defined load pockets must procure a percentage of their total capacity requirement from suppliers of qualified capacity electrically located within defined constrained areas. There was some discussion that the load pockets could be defined as the existing local reliability areas.

Parties who oppose adoption of this deliverability screen argue that deliverability to load pockets is more appropriately addressed in the CAISO's grid planning process than as a resource adequacy requirement. These parties worry about duplicative analysis of deliverability to load pockets being performed in the grid planning process and resource adequacy showing. One party suggests that one of the outcomes of the grid planning process should be a plan to identify units needed in load pockets, thus obviating the need for any local procurement or load pocket deliverability requirement in the resource adequacy showing. These parties argue that the Commission did not adopt a load pocket deliverability or procurement requirement and if a load pocket must also carry reserves at the same level as the system, the adopted planning reserve margin might need to be revisited. These parties are concerned that if a load pocket procurement requirement is adopted, the generators in that load pocket will be able to exercise market power and LSEs will end up procuring more reserves than required by the Commission's adopted planning reserve margin.

Another issue that arises in considering whether to adopt a load pocket deliverability or a local procurement requirement is how it would be applied to all LSEs within load pocket, given that some LSEs in a load pocket might be the local reliability area divided by peak load in the local reliability area. This can be expressed formulaically as:

$$\text{Local Procurement \%} = \frac{\text{Import Limit MW}^{41}}{\text{Peak Load MW}}$$

Some parties expressed concern that several things must occur if a local procurement requirement is imposed in load pockets. For example, the CAISO must define load pockets specifically enough to establish procurement objectives in advance; dispatch requirements need to be defined (specific and in advance); equity between LSEs must be addressed and distributed; and FERC must act on market power mitigation prior to contracts being negotiated by LSEs to meet local procurement requirements.

The Commission must decide whether deliverability should be assessed on aggregate basis or load pocket basis. In the event that the Commission decides that deliverability need only be addressed on aggregate, no additional decisions with respect to deliverability need to be made for an LSE to make its year-ahead resource adequacy showing. In the event that the Commission decides that a load pocket procurement requirement or deliverability into load pocket screen should be adopted, additional work is likely required as parties focused their discussion on whether or not this requirement was needed, not on how to accomplish it if it was adopted, although a potential short term solution was identified.

---

[41] This could be defined as the Capacity Transfer Limit which is described in Attachment 3 to Appendix D.

The Commission must decide whether it wishes to entertain this requirement at this time.

7.2 Allocation of DWR Contracts to All LSEs

Right now it appears that the utilities intend to rely on the DWR contracts consistent with the manner in which the contracts were allocated to them in D.02-09-053. At least one party asked that we discuss the possibility of allocating the capacity value associated with the DWR contracts (however the Commission decides they are to be given full credit and value) on a pro rata basis to LSEs based on their contribution to contract costs.[42] The advocates for an allocation of the capacity value to LSEs argue that this approach is consistent with the requirement that direct access customers pay a share of the contracts as determined in the cost responsibility surcharge proceeding, has the potential to assist with the load shifting problem by ensuring that the benefit stays with the customer. There was vigorous dispute between the parties about whether the costs allocated to direct access customers in the cost responsibility surcharge are only the above market portion of the DWR contracts costs and just what the "indifference" value used to assign cost responsibility represents. Opponents argue that (1) the Commission has been allocating stranded costs for years but has never tied the contracts to such allocation; (2) allocating DWR capacity value to non-utility LSEs would give LSEs credit for resources they don't actually use for serving load; (3) legislative history supports allocating the full value to utilities; and (4) allocation to non-utility LSEs raises operational concerns, and

---

[42] Although it was not discussed in any detail at the workshop, this same issue applies to utility retained generation and QF capacity. It is the belief of the workshop moderator that, unless directed otherwise, the utilities plan to rely on retained generation based on their ownership share in the facility and QF contracts that they are parties to for purposes of their year-ahead showing.

resources can be shared more effectively between LSEs because they know that the product will meet the Commission's resource adequacy requirements.[43]

At the May 18, 2004 workshop, two capacity tagging proposals were discussed, one sponsored by the Silicon Valley Manufacturing Group (SVMG) and one by SDG&E. The proposals contain specific recommendations about the definition of "capacity tags" and what a market to trade tagged resources should look like.[44] Although they were discussed at the workshop, agreement was not reached regarding the market component of the proposals. This report does not lay out the discussion about the market mechanisms in each proposal because of the exploratory nature of the discussion. However, parties appeared to reach general agreement about the minimum requirements a resource must satisfy to receive a capacity tag. Parties believe that the Commission must define what an acceptable product to receive a capacity tag is, but it is less important for the Commission to be involved in establishing or approving a trading mechanism.

A capacity tag would be for a specified amount of capacity (i.e., 1 MW) from a resource, based upon the definition of qualifying capacity for that type of resource, that also passes the deliverability screen. The parties refer to this part of the minimum requirements as being "certified". For example, a resource whose QC=30 MW and is fully deliverable would be eligible to receive 30 capacity tags if it also commits to offering its energy output to the CAISO spot market. The must offer obligation for energy provides a link between the advance capacity commitments and the need for those resources to offer energy in real time. Thus,

---

[43] Parties noted that right now, the electricity market is an energy product market, not a capacity market.
[44] The SVMG proposal was filed as an attachment to SVMG's pre-hearing conference statement in R.04-04-003. On and is not reproduced here. The SDG&E proposal was a summary of positions that SDG&E took in testimony during hearings in R.01-10-024 and is not reproduced here.

SCE's Comments to Question #4 Raised in the Counting Workshop, April 6-7, 2004

"When is a year in advance for purposes of assessing resource adequacy?"

The Resource Adequacy Workshops on Counting Issues held on April 6-7, 2004, identified five issues that were not fully discussed during these workshops due to time constraints. These issues were placed on the agenda for the added workshop scheduled on April 26, 2004. SCE was assigned one of these issues as stated above.

Decision D.04-01-050 "...establishes a requirement that utilities forward contract 90% of their summer (May through September) peaking needs (loads plus planning reserves) a year in advance..."[1] The issue is whether a "year in advance" is defined as: (1) twelve months in advance, (2) by the end of the previous calendar year, or (3) some other definition.

In SCE's Opening Comments on Resource Adequacy, dated March 4, 2004, SCE addressed the issue as follows[2]:

> SCE defines "a year in advance" to be a calendar year prior to the summer month in question. For example, to meet the resource requirement of May 2008, the LSE will forward contract 90% of its peak demand plus reserve margin prior to the end of 2007. Therefore, the appropriate coverage of the peak demand that LSEs must demonstrate for May 2008 will be (.90 * 1.15 * peak demand) or 103.5% of the May 2008 peak demand, and the LSE will forward contract this capacity prior to December 31, 2007.

Other parties, including the working group dealing with the load forecast issues, have suggested setting the "year in advance" definition to mean that the required resources need to be confirmed by April (or earlier) in the year prior to the summer in question. For example, under one proposal, 90% of the May – September 2008 resource adequacy requirement would be forward contracted by April 30, 2007.

SCE makes its recommendation for many reasons, but the primary reason being that Conclusion of Law #7 in D.04-01-050 states that "The utilities shall meet this 15-17% requirement by no later than January 1, 2008." Since this 15-17% requirement is designed to be the target reserve level in the summer of 2008 it appears that this language allows the utilities until December 31, 2007 to meet this requirement. This language seems to impute that by meeting this reserve margin target by the last day of the preceding year that this will meet the "year in advance" requirement.

SCE also has two other considerations in mind: (1) minimizing the costs to ratepayers of meeting these resource adequacy requirements, and (2) having sufficient information available which will allow informed and logical procurement decisions for the following summer.

---

[1] D.04-01-050, page 11

[2] Footnote 6

LOAD FORECASTING STRAWPERSON[1]
Submitted 4/09/2004

Resource Adequacy Requirements Workshops in R.01-10-024

PREFACE

This report addresses several issues related to developing the load forecasts which D.04-01-050 requires LSEs to use in conjunction with a planning reserve margin to make forward commitments to resources. D.04-01-050 covers all LSEs under the jurisdiction of the CPUC, e.g. IOUs, ESPs, and CCAs.

This report has been prepared by a self-selected team of interested parties following the March 16, 2004 "kickoff" workshop in the resource adequacy workshops called by an ALJ Ruling dated February 13, 2004. This is final "strawperson" report, and the component sections have been discussed in two multi-party conference calls.

Pursuant to the direction of ALJ Cooke, this "strawperson" report has been scheduled to be discussed in an open public workshop on April 14, 2004.

I. WHO PREPARES LOAD FORECASTS FOR WHAT CUSTOMER BASE?

D.04-01-050 creates resource adequacy requirements for all LSEs under the jurisdiction of the CPUC, e.g. IOUs, ESPs, and CCAs. It is unclear who is to prepare load forecasts and what loads are to be included in these load forecasts.

The remainder of Section I discusses two options for preparation of load forecasts:

a. IOU for Its Current Customers and Expected Load Growth, and ESP for the Load of Its Current Customers and Their Expected Load Growth

The over-arching concern is that the load of EVERY customer is the responsibility of some load serving entity. One way to insure coverage is to agree on a methodology whereby the ESPs forecast of load during the forecast horizon is based on load projections of the current roster of ESP customers, including the growth in load of these customers as permitted by existing contracts as well as any reduction in load due to energy efficiency. The IOUs forecast, in contrast, will assume that all existing IOU bundled customers will remain on IOU bundled service <u>and</u> that all new customers will also take IOU bundled service. This methodology will insure that all customer loads, both existing and new customers, will be explicitly covered by an LSE.

Pros	Cons
The plus side of this methodology is that all customer loads, both existing and new customers are covered by an LSE forecast	This methodology will tend to overstate/understate the true load responsibility of ESP's /IOU's to the extent that customers change service providers during the forecast period.
This method does not require extensive "reconciliation" or "iteration" between the IOU forecast and the various ESP forecasts or among the ESP forecasts	
This method allows for fairly straight-forward verification of IOU and ESP load forecasts as the recent historic loads of the current roster of each IOU's and each ESP's customer base is known.	

[1] As a collaborative effort to identify issues, this document does not have the endorsement of any party.

There are two options which define alternative extents to which losses are included within the load forecasts submitted by each LSE. These are:

(1) End-use metered usage plus losses up to the ISO-interface

This would be the definition of load that LSEs send to the ISO for settlement purposes. It is hourly load at the customer meter (either from hourly meters, or load profiled) plus distribution losses. Distribution loss factors by voltage level are published by the IOU's for all ESP's within their service area to use for ISO settlement purposes, so under the current process we are all using distribution losses calculated in a compatible manner. This definition does not adjust LSE load for transmission losses, UFE or any other adjustments.

Pros	Cons
Uses CPUC-approved method for adjusting for distribution system losses	Excludes a portion of losses traditionally included in "peak" measurements
Consistent with current ISO settlement processes.	Reduces "peak" loads which LSEs would have to satisfy leaving these the responsibility of the system operator
Does not require development and approval of a new method for computing additional losses beyond the CAISO-interface	
Consistent with current contractual structure whereby energy is purchased at the ISO interface.	Does not include either transmission losses or UFE which would be required in order for forecasting volumes to be converted to a "generation" concept. UFE and transmission losses could sum to as much as 5% at time of peak.

(2) End-use metered usage plus losses to the generation busbar

This is Option 1 above plus transmission losses, UFE and other adjustments reflected in the differences between SCADA real-time metered loads and end-use customer loads. To implement this option requires that these "transmission" losses be added to the losses included in Option 1. The real-time loads monitored by the ISO and the IOUs on their EMS (energy management systems) for their respective control areas are measured at "generation". This load is defined as the sum of all generation within the control area (net of self generation serving customer load on the customer side of the meter) plus the net of imports minus exports to the control area. It is a "top down" measure of load, as compared to the "bottom up" definition of customer load as reported by LSEs to the ISO for settlement, and it is real time.

Conceptually, this load at generation is greater than the load as measured at the ISO interface by the amount of physical transmission losses between the generators and the ISO interface, which is commonly referred to as a "transmission loss factor". Edison has found that, in practice, this "transmission loss factor" has to account for more than just the physical losses. It also has to account for UFE and probably accounts for metering discrepancies between the real-time EMS systems and the billing meters (and distribution loss factors) used for settlement. IOUs or the CAISO should provide to the CEC the forecast transmission loss factor for their area, and the CEC should apply it equally to all LSE load to convert them from "at the ISO interface" to "at Generation".

Pros	Cons
Consistent with traditional definition of system peak measurements	The above approach does not use a GMM/TMM approach. There may be an entity who could identify its specific transmission path and transmission loss factor (which might be lower than what the IOU says is the system average transmission loss factor).

In this option, each LSE would report hourly loads for the highest 5, 10, or 20 hours in each of the five summer months. Using the load duration curve (LDC) as an analogy, the LSE would report the "top" of the LDC.

Pros	Cons
consistent with D.04-01-050 and ALJ Ruling dated 2/13/2004	Contains much less information than either option 1 or 2
minimum amount of work involved	Limits options with respect to counting of resources.
	Inconsistent with Section IV.a of this report, since it would be impossible to determine true coincident loads for the CAISO control area if LSEs only submit a limited number of their own "high load" hours without time stamping

(4) Recommendation

The load forecasting team recommends that option (1) be implemented. Option (3) is not workable, because chronological hourly loads are essential to understanding coincidence of individual LSE loads to form the CAISO control area peak. The method of coincidence adjustment proposed in Section IV.a could not be implemented without hourly loads. Option (2) may be outside of the scope of the monthly analyses required by D.04-01-050.

d. Quantification of Energy Efficiency and Customer-Side of the Meter Distributed Generation Impacts

It is understood that LSEs account for "price induced" load responses as part of their base load forecasts. This section addresses the impacts from program impacts that are not motivated by prices. Expected "real" energy efficiency program impacts and the amount of distributed generation on the customer side of the meter are separately subtracted from the LSE's "base" load forecast (e.g. the net forecast is lower with these effects included than the gross forecast without them).

(1) Energy Efficiency (EE) Program Impacts

Energy efficiency load reductions for the forecast period should be deducted from the base load forecast, irrespective of how these programs are funded or who is the program delivery agent. For these purposes, "committed" energy efficiency (EE) refers to CPUC approved PGC- and procurement-funded programs.

Energy efficiency load reductions for forecasts are conceptually developed in two stages. For some forecasting methodologies, these two stages can be subsumed into a single process. The first stage is to determine the historical impact of energy efficiency programs. This can be done directly, buy using the Commission adopted measurement protocols and procedures to determine program or measure-level savings. It can also be done indirectly, as through a forecasting model which captures the impact of historical load reductions. (This is the approach PG&E uses for PGC-funded EE.)

The next conceptual step is to extrapolate those load reductions into the future (in this case, for the next summer.) In the case of an explicit forecast, the measured program or measure-level impacts are extrapolated using CPUC approved budgets ("committed EE") or budgets not yet approved by the CPUC ("uncommitted EE"). For year ahead forecasts, uncommitted EE will typically occur at the end of a funding cycle. For example, current EE budgets are approved through 2005, so forecasts for that year will be committed EE. When the forecast is not explicit, for example embedded in a forecasting approach, the forecasts made with the model will implicitly include historical levels of EE. A final step in most case is to provide the forecast in hourly detail. This generally utilizes historical load shape data at an appropriate level of desegregation.

As long as the steps of this process continue to be done under CPUC oversight, as for example, using the Commission' adopted measurement studies or protocols, the resulting forecasts should be included without alteration in resource adequacy computations.

In this option, all price sensitive demand reduction is subtracted from the "base" load forecast regardless of whether a program is dispatchable by the LSE or not. For dispatchable DR programs, the LSE has the right to trigger a demand reduction at a pre-set strike price. For a non-dispatchable DR, the customer chooses when and at what price to reduce demand, and the LSE estimates the demand reduction associated with different price levels when preparing its load forecast.

Arguments in favor of Alternative 2 (against Alternative 1)

Price sensitive DR programs are treated consistently. That is, both dispatchable and non-dispatchable DR are treated as demand reduction because both result in a demand reduction regardless of whether the LSE has dispatch rights. When the LSE exercises its dispatch rights, it will reduce its demand and the reserves associated with that load reduction. In both cases, the LSE would not carry reserves for load that is not projected to materialize at a given price.

(2) Interruptible/Curtailment Programs for Reliability

There are two options for the treatment of interruptible or emergency programs, which are intended only to be operated when the reliability of the system is threatened:

a) Treat Impacts as a Supply Option

In this option, the impacts of interruptible tariffs and programs are not to be subtracted from "base" load forecasts, but rather carried as resources.

Arguments in favor of Alternative 1 (against Alternative 2):

Dispatchable DR is treated as a supply resource because the demand reduction associated with these programs is already part of the LSE's reserves.

b) Treat Impacts as a Load Reduction

In this option, the impacts of interruptible tariffs and programs are subtracted from "base" load forecasts to the limit of each program.

Arguments in favor of Alternative 2 (against Alternative 1)

When the ISO calls for a Stage 2 curtailment, the LSE experiences a reduction in demand and associated reserves. The LSEs does not need to carry reserves on interruptible load since this is by definition non-firm load and the customer has been already been paid to curtail under prescribed rules. If treated as a "supply-side option", in order to achieve the same effect, the expected demand reduction would need to be grossed by the required reserves in order to capture the no-reserve need for interruptible load.

f. Weather and other Short-Term Variations

Values for weather variables and other factors inducing short term variation in loads should be chosen to represent expected (50:50) loads for each of the five summer months.

III. REPORTING AND COMPLIANCE

This section of the report addresses a number of topics which are essential to be resolved for reporting and compliance purposes. Understanding these reporting and compliance purposes helps to define the nature of the load forecasts.

a. Timing of Annual Compliance Submittals

c) Basic documentation of customer counts[5], methodology, program impacts included (EE, DG, PRD, etc.)
d) Narrative explanation of any significant factors

These elements of documentation are necessary for any of the analyses discussed in Section V.c. A documentation submission requirement would be new to non-IOU LSE that they are not used to satisfying. At least for utilities, no greater effort is implied by the proposed documentation than would be required by CEC's biennial planning requirements. Both ESPs and IOUs suggest that such filings could create confidentiality concerns that would have to be resolved.

c. Confidentiality of Load Forecast Submittals[6]

The following are aspects of the confidentiality issue yet to be fully discussed or resolved, but that both IOUs and ESPs have raised:

(1) All LSE-specific hourly load forecasts are confidential and will not be submitted to any reviewing entity except with that understanding. Access to such data will be limited and follow the usual non-disclosure agreement practices.

(2) At some level of aggregation, loads are no longer confidential and such "higher level" results can be prepared and released by the reviewing entity(s). No discussion of at what level of load aggregation shifts from confidential to public has yet taken place.

It is likely that these confidentiality concerns exist for other categories of data which are part of these resource adequacy compliance filings, and therefore the confidentiality issue should be resolved in a comprehensive manner.

IV. USE OF LOAD FORECAST AS A BASIS FOR FORWARD COMMITMENT OBLIGATIONS

The ALJ Ruling dated February 13, 2004 raised the issue of confidence adjustments among LSE forecasts. This section of the report addresses how coincidence would be assessed from among filings submitted by LSEs, and then discusses options for making use of the diversity information gained from such an analysis.

a. Coincidence Analysis

The CEC proposes two possible methods for adjusting for the coincident control area peak load on the basis of the hourly load forecasts of each LSE, and then using this information to identify the each LSE's load at the coincident peak.[7]

(1) Computing Coincidence Directly from LSE Submitted Forecasts

This method assumes all LSEs within the CAISO control area provide hourly forecasted load for the summer months.[8] The designated load for the forward obligation is based on each LSE's share of total load during the CAISO's coincident peak hours, rather than LSE loads on their individual peak days, using the following steps:

---

[5] ESPs do not believe that individual customer by customer information should be provided. Aggregate counts of customers should be sufficient.
[6] This section was inserted after the 3/26/2004 conference call at the suggestion of Art Canning. No one has yet volunteered to write this section up.
[7] Note that these proposals require selection of either Option (1) or (2) in Section II.b for all LSEs.
[8] Since there are numerous publicly-owned utilities within the CAISO control area, this method requires that either the CEC or the CAISO require a comparable hourly load forecast from entities outside the CPUC's jurisdiction. The CEC has the legal authority to require such load forecasts for all "utilities" in California, and the CEC is currently evaluating whether it will resume such a requirement.

As an aid to understanding of load diversity, a supplemental analysis in parallel to either of the above two options could be undertaken using temperature data for the three IOU service areas, which is available for 30 or 40 historical years. The CEC could take a weighted average temperature by service area and compare those service area temperatures to the weighted average for the ISO control area for the 40 historical years, and calculate a diversity of temperatures relative to the day of the ISO area hottest temperature. The CEC may have factors such as MW per degree Fahrenheit for each area, or could request and coordinate such analysis with the IOUs such that the temperature diversity could be converted to a peak hour MWh diversity. This would give a long term view of diversity and give insight as to frequency and probability of coincident high temperatures, but only looking at IOU total loads versus the ISO total load. This method gives no insight to diversity between bundled and DA load within an IOU service area. However, it does answer part of the diversity question with an analysis of long-term data, which is not available directly from LSE load data.

b. Use of Coincidence Results

To the extent that diversity among LSE hourly loads is found, what should be done with this information? The following are options:

(1) Adjust for Coincidence

In this option, each LSE's forward obligations would be explicitly reduced by adjusting the original LSE load forecast for a monthly coincidence factor so that the "final" LSE load forecast used for compliance determination is lower than the original, non-coincident one.

Pros	Cons
Forward obligations for a specific based upon that LSE's actual contribution to system peak	Implementation may require "finetuning" of language in D.04-01-050
If diversity is not taken into account then LSE's will be systematically over-procuring resources in "aggregate".	May result in additional proceedings regarding methodology of calculation and application of diversity factors.

(2) Ignore Coincidence

In this option the coincidence analysis described in Section V.a would not be used to adjust each LSE's load forecast or their forward commitment obligations relative to these load forecasts. Instead, the coincidence analyses would provide an understanding of the "cushion" provided by non-coincidence of individual LSE load forecasts and the benefits this has to further assure reliable system operation.

Pros	Cons
The diversity among individual LSE loads would create an additional "cushion" so that effective planning reserves were greater thsan the 15-17% of system peak adopted in D.04-01-050	LSE's obligated to acquire higher level of resources, perhaps 1-5% of there own peak loads, thus costing more money than if diversity were accounted for
Explicit coincidence analysis reveals the actual size of this "cushion"	Theoretically more correct to account for diversity directly than to use indirect means of "adjustment".
Avoid delays in approving compliance filings based on debates regarding calculation and application of diversity factors	

c. Analyses that could be Conducted for Each LSE's Submittal

The following are different analyses that could be conducted on each LSE's load forecast submittal once it has been filed. One or more of these analyses could be conducted, so there are elements of an evaluation process, not options. One or more different entities might be involved in such analyses.

The water pumping loads of the State Water Project and its water contractors are a good example. SWP loads are based upon the amount of water moved through the SWP's system of pumps, which amount varies significantly from year to year. Since future SWP loads are subject to fluctuating hydrology conditions, they may not be closely aligned with recent load history. There are corresponding impacts on the state water contractors at the point of local water deliveries as these agencies use more of less ground water pumping depending upon availability of surface water deliveries.

Load forecasts for non-traditional LSEs such as the SWP should reflect, where appropriate, acceptable levels of service risks and flexible delivery times. Establishing a reserve requirement using forecasted loads for May through September a year in advance may not make sense for a non-traditional LSE such as the SWP whose water delivery requirements are not known until the end of the precipitation season, which is typically the end of April in a current year. A load forecast a year in advance could vary over the full range of historic hydrology. Since non-traditional LSEs such as SWP have direct control over the timing of their loads with flexibility during a month, and most of its load is served during the off-peak periods when resource adequacy for a control area is generally not a concern, they should enjoy greater flexibility in load forecasting and establishing reserve requirements.

Pros	Cons
More accurate load forecasts	Requires greater documentation to explain how fluctuations were built into the load forecast
	Greater complexity in reviewing LSE submittals

c. Load Forecasts Covering the Period One and More Years Ahead

As described in Section II.a of this report, each LSE will provide a forecast in the spring of the year for each of the five summer months of the following year. Most LSEs will prepare forecasts with longer time horizons in order to appropriately consider a portfolio of resources to cover expected loads. In order to facilitate planning, these forecasts could be provided for a five-year forecast horizon. Thus, in April of each year forecasts would be provided for the period May-September of the next five years, e.g. submissions made in April 2005 for May – September 2006
May – September 2007
May – September 2008
May – September 2009
May – September 2010

Pros	Cons
Lead time to build resources takes more than a one-year time frame.	One year ahead is the maximum commitment under the current rules, so no additional information needed for a compliance filing
A five-year ahead forecast would provide much better information for planning purposes.	ESP commercial contracts generally are not long-term in nature and, therefore, the ESP's ability to make long-term forecasts/commitments may be impacted.
A five-year ahead forecast would draw attention to the policy concern between directed planning and commercial feasibility.	

d. Rolling Twelve Month-Ahead Load Forecasts

Neither of the options described in Section I of this report provides a good method to address the expected load for ESPs. The first would require an estimate of the load under contract as of the point the forward planning process required a submittal, as though these were actually the expected load. As ESP's relationship with a customer is contractual, with a specified term, requiring an ESP to forecast load based on current customers may overstate ESP load and thereby require ESPs to secure, on a forward contract basis, reserves in excess of its requirements. Since

For new LSEs that do not have extensive historical load data on hand to calculate year- or more-ahead forecasts IOUs will need to be willing and able to provide sufficient historical load information to facilitate the best-informed LSE load forecasts. This may mean that for certain LSEs, CCAs for example, IOUs may need to provide up to 10 years of historical load data for a given city, county, or group of cities and counties (i.e., Joint Powers Authority). It will be imperative that this cooperation and coordination take place to ensure that accurate load forecasting occurs and resource adequacy requirements are met. Cooperation between IOUs and CCAs will also be required regarding economic forecasts that underpin load forecasts. Cooperation will also be required between IOU's and CCA's regarding load profiling data e.g. some CCA's may need to site more load profile meters to establish a statistically valid load profile sample for forecasting and other purposes.

Appendix C

NERC GADS Definitions

Operation and Outage States

Actual Unit Starts
Number of times the unit was actually synchronized

Attempted Unit Starts
Number of attempts to synchronize the unit after being shutdown. Repeated failures to start for the same cause, without attempting corrective action, are considered a single attempt.

Available
State in which a unit is capable of providing service, whether or not it is actually in service, regardless of the capacity level that can be provided.

Forced Derating (D1, D2, D3)
An unplanned component failure (immediate, delayed, postponed) or other condition that requires the load on the unit be reduced immediately or before the next weekend.

Forced Outage (U1, U2, U3, SF)
An unplanned component failure (immediate, delayed, postponed, startup failure) or other condition that requires the unit be removed from service immediately or before the next weekend.

Maintenance Derating (D4)
The removal of a component for scheduled repairs that can be deferred beyond the end of the next weekend, but requires a reduction of capacity before the next planned outage.

Maintenance Outage (MO)
The removal of a unit from service to perform work on specific components that can be deferred beyond the end of the next weekend, but requires the unit be removed from service before the next planned outage. Typically, a MO may occur anytime during the year, have flexible start dates, and may or may not have a predetermined duration.

Planned Derating (PD)
The removal of a component for repairs that is scheduled well in advance and has a predetermined duration.

Planned Outage (PO)
The removal of a unit from service to perform work on specific components that is scheduled well in advance and has a predetermined duration (e.g., annual overhaul, inspections, testing).

Reserve Shutdown (RS)
A state in which a unit is available but not in service for economic reasons.

APPENDIX C: NERC GADS Definitions

Equivalent Unplanned Derated Hours (EUDH)*
The product of the Unplanned Derated Hours (UDH) and the Size of Reduction, divided by the Net Maximum Capacity (NMC).

Forced Derated Hours (FDH)
Sum of all hours experienced during Forced Deratings (D1, D2, D3).

Forced Outage Hours (FOH)
Sum of all hours experienced during Forced Outages (U1, U2, U3, SF).

Maintenance Derated Hours (MDH)
Sum of all hours experienced during Maintenance Deratings (D4) and Scheduled Derating Extensions (DE) of any Maintenance Deratings (D4).

Maintenance Outage Hours (MOH)
Sum of all hours experienced during Maintenance Outages (MO) and Scheduled Outage Extensions (SE) of any Maintenance Outages (MO).

Period Hours (PH)
Number of hours a unit was in the active state.

Planned Derated Hours (PDH)
Sum of all hours experienced during Planned Deratings (PD) and Scheduled Derating Extensions (DE) of any Planned Deratings (PD).

Planned Outage Hours (POH)
Sum of all hours experienced during Planned Outages (PO) and Scheduled Outage Extensions (SE) of any Planned Outages (PO).

Pumping Hours
The total number of hours a turbine/generator unit was operated as a pump/motor set (for hydro and pumped storage units only).

Reserve Shutdown Hours (RSH)
Sum of all hours experienced during Reserve Shutdowns (RS). Some classes of units, such as gas turbines and jet engines, are not required to report Reserve Shutdown (RS) events. Reserve Shutdown Hours (RSH) for these units may be computed by subtracting the reported Service Hours (SH), Pumping Hours, Synchronous Condensing Hours, and all the outage hours from the Period Hours (PH).

Scheduled Derated Hours (SDH)
Sum of all hours experienced during Planned Deratings (PD), Maintenance Deratings (D4) and Scheduled Derating Extensions (DE) of any Maintenance Deratings (D4) and Planned Deratings (PD).

APPENDIX C: NERC GADS Definitions

Net Maximum Capacity (NMC)
GMC less the unit capacity utilized for that unit's station service or auxiliaries.

Net Dependable Capacity (NDC)
GDC less the unit capacity utilized for that unit's station service or auxiliaries.

Net Availability Capacity (NAC)
GAC less the unit capacity utilized for that unit's station service or auxiliaries.

Net Actual Generation (MWh) (NAG)
Actual number of electrical megawatthours generated by the unit during the period being considered less any generation (MWh) utilized for that unit's station service or auxiliaries.

***Notes:**

-- Equivalent hours are computed for each derating and then summed.
-- Size of reduction is determined by subtracting the Net Available Capacity (NAC) from the Net Dependable Capacity (NDC). In cases of multiple deratings, the Size of Reduction of each derating is the difference in the Net Available Capacity of the unit prior to the initiation of the derating and the reported Net Available Capacity as a result of the derating.

Equations

Availability Factor (AF)
[AH/PH] x 100 (%)

Equivalent Availability Factor (EAF)
[(AH - (EUDH + EPDH + ESEDH))/PH] x 100 (%)

Equivalent Forced Outage Rate (EFOR)
[(FOH + EFDH)/(FOH + SH + EFDHRS)] x 100 (%)

Forced Outage Factor (FOF)
[FOH/PH] x 100 (%)

Forced Outage Rate (FOR)
[FOH/(FOH + SH)] x 100 (%)

Gross Capacity Factor (GCF)
[Gross Actual Generation/(PH x GMC)] x 100 (%)

Gross Output Factor (GOF)
[Gross Actual Generation/(SH x GMC)] x 100 (%)

Net Capacity Factor (NCF)
[Net Actual Generation/(PH x NMC)] x 100 (%)

APPENDIX C: NERC GADS Definitions

$$\text{EFDH} = \frac{\sum_{i=1}^{N} \text{EFDH}_i}{N}$$

$$\text{EFDHRS} = \frac{\sum_{i=1}^{N} \text{EFDHRS}_i}{N}$$

Note: All computed values are rounded to the nearest hundredth. Entries of 0.00 signify the averaged values are less than 0.005.

Average Number of Occurrences Per Unit-Year

$$= \frac{\text{Number of Outage and/or Derating Occurrences}}{\text{Number of Unit-Years}}$$

Average MWh Per Unit-Year

$$= \frac{\text{Hours for Each Outage and/or Deratina Type x NMC (MWI}}{\text{Number of Unit-Years}}$$

Average Hours Per Unit-Year

$$= \frac{\text{Hours for Each Outage and/or Derating Type}}{\text{Number of Unit-Years}}$$

Average Equivalent MWh Per Unit-Year
Computed as shown in the equation for **Average MWh Per Unit-Year** above, except the deratings are converted to equivalent full outage hours. Equivalent hours are computed for each derating event experienced by each individual unit. These equivalent hours are then summarized and used in the numerator of the **Average MWh Per Unit-Year** equation. Each equivalent hour is computed as follows:

$$\text{EQUIVALENT OUTAGE HOURS} = \sum \frac{\text{Derating Hours x Size of Reduction}}{\text{NMC (MW)}}$$

Average Equivalent Hours Per Unit-Year
Computed as shown in the equation for **Average Hours Per Unit-Year** above, except the deratings are converted to equivalent full outage hours. Equivalent hours are computed for each derating event experienced by each individual unit. These equivalent hours are then summarized and used in the numerator of the **Average Hours Per Unit-Year** equation.

Notes:
--All computed values are rounded to the nearest hundredth. Entries of 0.00 signify the averaged values are less than 0.005.

APPENDIX D
Draft #2

"STRAW-PERSON" DELIVERABILITY PROPOSAL

Deliverability is an essential element of any resource adequacy requirement. Specifically, Load Serving Entities (LSEs) must be able to show that the supplies they intend to procure to meet their load requirements can be delivered to load when needed. Otherwise, such resources are of little, if any, value for the purposes of resource adequacy.

The California Public Utilities Commission (CPUC) is considering how to require the LSEs to demonstrate the deliverability of the resources they procure in both their annual resource plans and their long-term resource plans. This is essential so that the LSEs will be able to "count" their resources to determine whether they satisfy the planning reserve margin, and to ensure sufficient coordination between resource planning and transmission planning.

This paper and three attachments offer a "Straw-Person" proposal for deliverability with technical details on this proposed methodology. Draft 1 of this paper was the focus of a six-hour meeting and a two-hour conference call involving approximately 30 participants, as well as written comments from eight participants as of April 5th. **Additional written comments on this Draft 2 are encouraged as a way to facilitate the on-going debate at the April 12-13 workshops.**

The stakeholder discussions and written comments raised a number of general policy issues that go beyond the scope of this paper. A number of these issues were listed in a March 26, 2004 memo from the ISO's Phil Pettingill (on behalf of the Deliverability workgroup) to the entire Resource Adequacy service list. This paper carves out several other policy issues that could be separated from this proposed methodology and technical explanation for determining deliverability.

This proposed straw-person deliverability proposal consists of three assessments: Deliverability of Generation to the Aggregate of Load, Deliverability of Imports, and Deliverability to Load Within Transmission Constrained Areas. This third test involving deliverability to load pockets was debated extensively among stakeholders involved in this Deliverability test. As explained below, this third type of assessment may be an issue for the larger Resource Adequacy group to consider as a general Resource Adequacy requirement, rather than be subsumed as a third part of this technical Deliverability assessment.

Each of these assessments is discussed in greater detail below and in the Attachments.

A. Deliverability Of Generation To The Aggregate Of Load

As part of developing its proposal to comply with FERC's Order No. 2003 regarding the interconnection of new generating facilities, the ISO developed and proposed to FERC a "deliverability" test (but not a requirement). The purpose was to begin to assess the deliverability of new generation to serve load on the ISO's system. Recent experience

B. Deliverability of Imports

California is now, and will likely remain, dependent on imports to satisfy its energy and resource requirements. Therefore, it is likely that as part of fulfilling their obligation to procure sufficient resources (reserves) in the forward market to serve their respective loads, the IOUs will contract with out-of-state resources. This is appropriate and necessary.

The ability to rely on imports to satisfy reserve requirements is entirely dependent on the *deliverability* of such out-of-state resources to and from the intertie points between the ISO's system and the neighboring systems. While the existing system may be able to satisfy the procurement plans of any one LSE, it likely will not be able to transmit the sum of LSEs' needs. Each LSE may well be utilizing the same potentially constrained transmission paths to deliver their out-of-state resources. Therefore, the transmission system should be checked to make sure that simultaneous imports can be accommodated.

When relying on imports to serve load, each LSE should be required to ensure that they have assessed the deliverability of such resources from the tie point to load on the ISO's system.

More specifically, this "Strawperson" proposes that each LSE, in conjunction with the ISO, be required to perform an integrated analysis on the annual procurement plans and the long-term procurement plans to ensure their identified resources are deliverable to load and that the necessary transmission capacity will exist on the system. Such an analysis should be performed using similar techniques used for operational transfer capability ("OTC") studies but would look at specific resource import scenarios expected in the future. Adverse internal generation availability and loop flow scenarios should be developed to adequately evaluate the capabilities of the transmission system to deliver imports to aggregate load.

Additionally, some kind of determination is needed regarding the ability of resources to be delivered to the tie point with California. Several stakeholders suggested a requirement for *firm* transmission rights over the neighboring system's transmission system would be too limiting, as some entities may want to optimize a portfolio of resources. This "Strawperson" proposal omits any deliverability requirement outside of California because it is beyond the scope of this technical explanation of a deliverability assessment. However, the ISO anticipates further discussion on the need for some kind of assurance that resources outside of California can deliver necessary MWs to the tie points.

In reviewing this paper several participants also questioned whether this Deliverability of Imports test is identical to the ISO's planned CRR simultaneous feasibility test (SFT). Both tests would use the same transmission network model for the same study year, and would consider the same contingencies. However, at this time the SFT models simultaneous flow limits in order to ensure that appropriate contingencies are covered, while the proposed Deliverability of Imports test has the ability to simulate each in rolling blackouts that were necessary to ensure compliance with the WECC Minimum Operating Reliability Criteria (MORC.)

Because the San Francisco Greater Bay Area Generation Outage Standard specifically considers the availability of resources, this facet of the ISO Grid Planning Process falls into a category where both Transmission Adequacy and Resource Adequacy overlap. The ISO Grid Planning Standards Committee periodically reviews other areas of the ISO Grid to determine if additional specific standards are necessary upon review of generation availability data within those other areas. If other special Standards were approved for other transmission constrained areas, presumably the Transmission and Resource Adequacy assessment methodologies would overlap for the areas covered by these Standards.

To further underscore the distinction between grid planning and resource adequacy standards, it should be noted that the CPUC's rulemaking on transmission assessment practices anticipates a resource planning process that considers the economic trade-off between Load, Transmission, Generation and possibly RMR contracts. The ISO Grid Planning process would be limited to considering only transmission projects after the other alternatives have been considered. "Staff suggests that the Commission's transmission determination made as part of its review of the IOUs long-term procurement plans should be reflected in the CAISO's transmission planning process."[1]

In addition, a NERC taskforce recently issued a series of draft recommendations, including support for the eventual creation of deliverability assessment standards: "NERC shall develop assessment practices and reporting processes to verify that resources identified by load serving entities (LSEs) to meet resource adequacy requirements are simultaneously deliverable to the LSEs' loads. The assessment practices shall also determine whether the simultaneous import capabilities are sufficient to satisfy the import capability assumptions included in the resource adequacy assessments."[2] Although implementation of such proposed NERC standards is not likely in the immediate future, this task force recommendation does indicate that deliverability is a distinct feature from the existing NERC/WECC Planning Standards, and that some minimum national standards for deliverability assessment are needed.

Finally, some participants within this Deliverability workgroup raised questions related to RMR criteria. This "Strawperson" proposal assumes that RMR criteria would be an insufficient test for deliverability *in the long-term* because RMR is a year-ahead process. The options for providing local area reliability service are limited to signing RMR contracts or capital projects that can be completed within one year. Because of these limited options, the RMR criteria are typically less stringent than the ISO Grid Planning Standards or this proposed Deliverability to Load assessment. These latter two

---

[1] Page 6, CPUC Rulemaking 04-01-026; Order Instituting Rulemaking on policies and practices for the Commission's transmission assessment process.
[2] Draft Resource and Transmission Adequacy Recommendations report, presented at the March 23-24, 2004 meeting of the NERC Resource and Transmission Adequacy Task Force.

process. Resources that pass the deliverability assessment could be counted to meet reserve margin requirements and resources that don't pass could not.

The Deliverability of Imports assessment would be performed during the review of all LSE's long term and short term resource plans. Firm import information is an input to the generation deliverability assessments. Therefore, new firm import procurement plans would need to be tested using the generator deliverability methodology to ensure that the additional imports do not impact the deliverability of generation that has already passed the generation deliverability test. Once the resource plans are approved, the import assumptions for future generation deliverability assessment would be updated as needed.

The Deliverability to Load test would be performed during the development of the *long term* resource plans. Solutions for resolving resource deficient load pockets could include the construction of resources needed to meet reserve margin requirements but located in the deficient load pocket to mitigate the deliverability to load deficiency. The construction of resources within the load pocket could be by any developer of generation—a procurement contract with that new generator should ensure that it is actually built.

The Deliverability of Imports and the Deliverability to Load in Transmission-Constrained Areas would, generally, utilize common methods and terminology. However, the definition of the area to be analyzed for the Deliverability of Imports assessment is already defined as the ISO Control Area boundary. This boundary is determined almost exclusively by facility ownership and service areas rather than electrical characteristics. In contrast, the boundary for load pockets to be analyzed would be determined only by electrical characteristics. Operational Transfer Capability (OTC) is a term that applies to WECC paths that correspond to most of the ISO Control Area Boundary. OTCs are not calculated for most load pocket boundaries because power is not scheduled across these boundaries.

Because the ISO lacks critical data necessary to conduct a meaningful "test-run" of this methodology, preliminary study results would be misleading. One participant helpfully suggested that, should results be required quickly in time for LSEs summer 2005 resource procurement activities, then historical data could be utilized. The ISO appreciates this suggestion but is concerned that planned transmission upgrades and new generation would not be considered. In addition, a review of the day-ahead, hour-ahead, and real-time markets for both inter-zonal and intra-zonal congestion for the peak load day for each of the summer months could take considerable time. The ISO also emphasizes that continued stakeholder input and review is strongly encouraged if any of these procedures are undertaken. It is fully expected that this deliverability validation process would be tested and evaluated on existing resources to ensure that the results are reasonable, equitable and consistent with engineering judgment, and that refinements will be made as needed.

A generator that meets this deliverability test may still experience substantial congestion in the local area. To adequately analyze the potential for congestion, various stressed conditions (i.e., besides the system peak load conditions) will be studied as part of the overall System Impact Study for the new generation project. Depending on the results of these other studies, a new generator may wish to fund transmission reinforcements beyond those needed to pass the deliverability test to further mitigate potential congestion—or relocate to a less congested location.

The procedure proposed for testing generator deliverability follows.

2.0 <u>Study Objectives</u>

The goal of the proposed ISO Generator deliverability study methodology is to determine if the aggregate of generators in a given area can be simultaneously transferred to the remainder of ISO Control Area. Any generators requesting interconnection to the ISO Controlled Grid will be analyzed for "deliverability" in order to establish the amount of deliverable capacity to be associated with the resource.

The ISO deliverability test methodology is designed to ensure that facility enhancements and cost responsibilities can be identified in a fair and nondiscriminatory manner.

3.0 <u>Baseline analysis</u>

Deliverability Test Validation: This procedure was derived from the deliverability test procedure currently used by PJM. Adaptations to the PJM procedure were necessary due to the considerable physical differences between the PJM system and the ISO-Controlled Grid. During the initial implementation of this procedure, it will be a tested, and evaluated on existing resources to ensure that the results are reasonable, equitable, and consistent with engineering judgment. Stakeholders will review the results of this validation process. The deliverability test procedure will be refined as needed.

In order to ensure that existing resources can pass this deliverability assessment, an annual baseline analysis, with the most up-to-date system parameters, must first be performed by applying the same methodology described below on the existing transmission system and existing resources. Identified deliverability problems associated with generation that exist prior to the implementation of this deliverability test may be mitigated by transmission expansion projects if the capacity is needed and/or the project is economically justifiable. Generation deliverability limitations on currently existing generation can be allocated among multiple generators contributing to the same problem based on the incremental flow impact that each generator contributes to the problem. The deliverability of both existing and new generators that are certified as deliverable will be maintained by the annual baseline analysis and the transmission expansion planning process.

Draft Straw-Person Deliverability Proposal

Attachment 1

Table 1: Resource Dispatch Assumptions

Resource Type	Base Case Dispatch	Available to Selectively Increase Output for Worst-Case Dispatch?	Available to Scale Down Output Proportionally with all Control Area Capacity Resources?
Must-Take Capacity Resources			
• Nuclear	maximum dependable capacity	N	Y
• QF contracts	historical output	Y (up to contract limit)	Y
RMR	Dispatch as necessary to meet local area requirements	Y	Y
Energy Limited Capacity Resources			
• Hydro	Drought conditions, historical output, 90% confidence factor* for output during summer peak load hours** (An average hydro scenario will also be analyzed)	Y	Y
• Combustion Turbines with run-hour limitations	Approximately 50% of dependable capacity	Y	Y
Other Dispatchable Capacity Resources			
• Combined cycle gas, Steam turbine gas/coal, geothermal, biomass	Approximately 90% of dependable capacity	Y	Y
Intermittent Capacity Resources			
• Wind	90% confidence factor* for output during summer peak load hours** (An average wind scenario will also be analyzed)	Y	Y
• Solar	90% confidence factor* for output during summer peak load hours** (An average solar scenario will also be analyzed)	Y	Y
Energy Resources	Minimum commitment and dispatch to balance load and maintain expected imports	N	Y
Imports			
• Existing Transmission Contracts	Schedule/flow at contract capacity	N	N
• Dynamic Schedules	Schedule/flow at contract capacity	N	N
• Unit contingent LSE Import	Schedule/flow at contract capacity	N	Y

Distribution Factor (DFAX)
Percentage of a particular generation unit's incremental increase in output that flows on a particular transmission line or transformer when the displaced generation is spread proportionally, across all dispatched resources "available to scale down output proportionally with all control area capacity resources in the Control Area", shown in Table 1. Generation units are scaled down in proportion to the dispatch level of the unit.

G-1 Sensitivity
A single generator may be modeled off-line entirely to represent a forced outage of that unit. This is consistent with the ISO Grid Planning Standards that analyze a single transmission circuit outage with one generator already out of service and system adjusted as a NERC level B contingency. System adjustments could include increasing generation outside the study area. The number of generators increased outside the study area should not exceed the number of generators increased inside the study area.

Municipal Units
Treat like all other Capacity Resources unless existing system analysis identifies problems.

Energy Resources
If it is necessary to dispatch Energy Resources to balance load and maintain expected import levels, these units should not contribute to any facility overloads with a DFAX of greater than 5% for 230 kV lines or below, or 10% for 500 kV lines. Energy Resource units should also not mitigate any overloads with a DFAX of greater than 5% for 230 kV lines or below, or 10% for 500 kV lines.

WECC Path Ratings
All WECC Path ratings (e.g. Path 15 and Path 26) must be observed during the deliverability test.

Pmax* DFAX Impact
Generators that have a (DFAX*Generation Capacity) > 5% of applicable facility rating or OTC will also be included in the Study Area.

Deliverability to Load in Transmission Constrained Areas

This deliverability assessment focuses on the delivery of energy from the aggregate of capacity resources to an electrical area experiencing a capacity deficiency. It can be discussed in the context of demonstrating the "deliverability to the load" as opposed to the "deliverability of individual generation resources". This ensures that, within accepted probabilities, energy will be able to be delivered to Control Area load, regardless of cost, from the aggregate of capacity resources available to the Control Area.

The determination of the reserve requirement is based on the assumption that the delivery of energy from the aggregate of capacity resources to control area load will not be limited by transmission capability. This assumption depends on the existence of a balance between the distribution of generation throughout the control area and the ability of the transmission system to reliably deliver energy to portions of the control area experiencing capacity deficiencies.

The specific procedures utilized to test deliverability from the load perspective involve the calculation of a Capacity Emergency Transfer Objectives (CETO) and Capacity Transfer Limits (CTL) for various electrical sub-areas of the ISO Control Area. A CETO represents the amount of MWs that a given sub-area must be able to import in order to remain within the CPUC resource adequacy framework requiring that the probability of occurrence of load exceeding the available capacity resources is consistent across the Control Area.

To analyze the deliverability to load, electrically cohesive load areas must first be defined. These areas are sub-areas of the ISO Control Area (e.g. San Francisco Bay area, San Diego area, LA Basin area, Fresno area, NP15, SP15, etc). These sub-areas are defined based on the impact of generators, potentially within the sub-area, on the contingencies known to limit operations in the sub-area. Sub-area boundaries could be drawn to include generators based on the calculated impacts on those contingencies. Load buses are similarly assigned to these sub-areas based on their impact on the same contingencies.

Once a sub-area is defined, the CETO for that sub-area must be calculated using a reliability simulation tool such as Henwood RiskSym, or GE MARS. Using the simulation tool, determine the import capability of the load area necessary to ensure the LOLP inside the area is consistent with the rest of the control area—this value is the CETO for that sub-area.

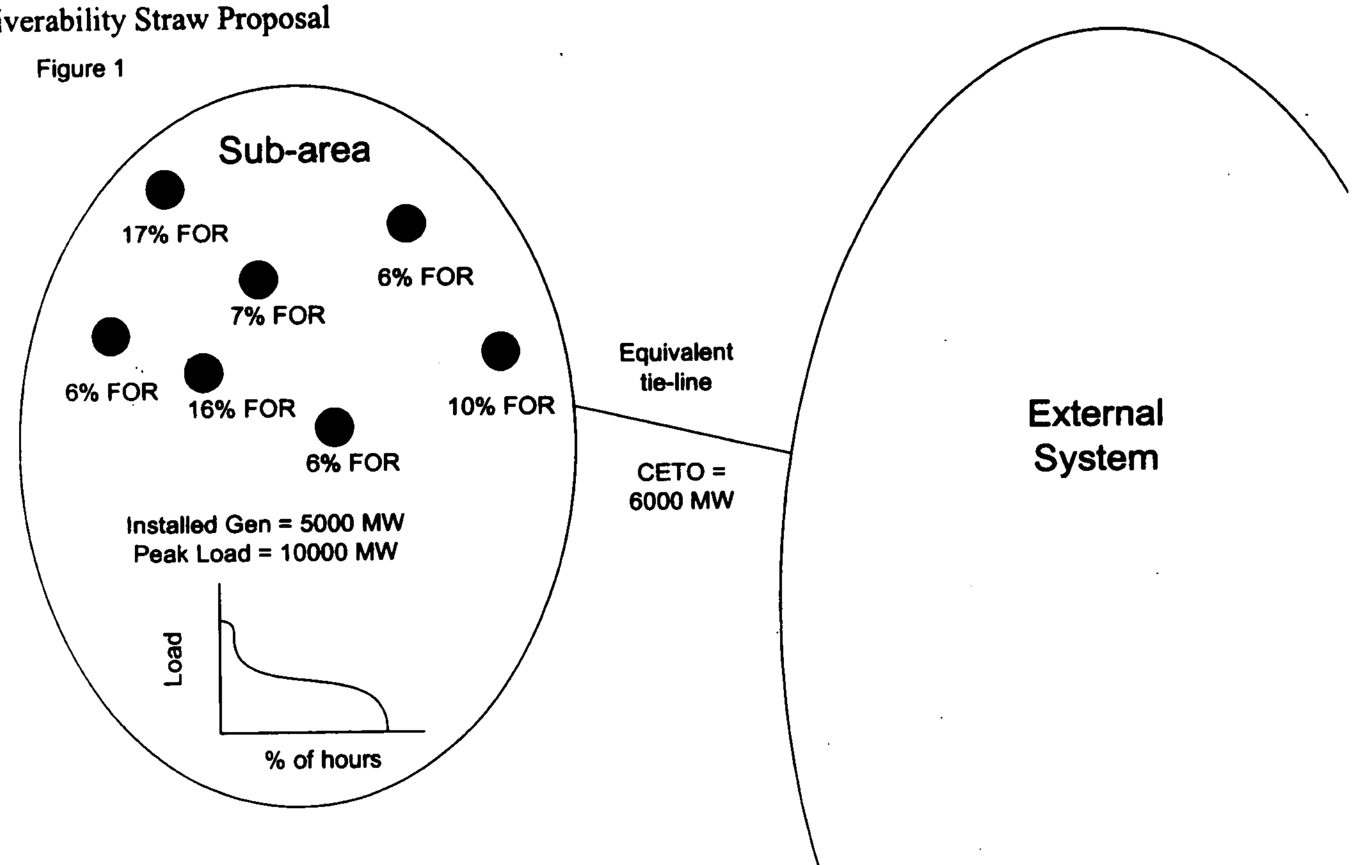
The next step in the analysis is to calculate a generation forced outage target (GFOT). The GFOT will be equal to the internal area generation (G) plus the CETO minus the internal sub-area peak load and losses (L) or GFOT = G + CETO – L. An example of this concept is shown in Figure 1.

Once the GFOT is determined, specific unit forced outage scenarios need to be developed for modeling within a power flow base case model. Using the individual generator

APPENDIX D

Deliverability Straw Proposal

Figure 1



* The LOLP of the Sub-Area changes based on transfer capability of the equivalent tie-line to the External System. However, th
transfer capability of the equivalent tie-line varies as a function of the generation pattern/availability inside the Sub-Area.
* The CETO is the minimum transfer capability of the equivalent tie-line that ensures that the LOLP target is satisfied.
* A full network powerflow model is then used to ensure that the CETO is achievable under reasonably expected generation ou
scenarios.
* In this example 1000 MW of generation would need to be forced out in various combinations in order to test the CETO in the
transmission analysis.

APPENDIX E

Assessment of Total Import Capacity

Deliverability Workshop Follow-Up: Assessment of Total Capacity into ISO Control Area

Background

At the CPUC's April 12-13, 2004 Deliverability Workshop, an action item was assigned to the California ISO. As requested, the ISO has been coordinating a detailed technical discussion and development of a proposal for establishing the total import capacity, for each import path, to be allocated to Load Serving Entities (LSEs) for resource adequacy planning purposes. This proposed approach will be presented at the next Deliverability Workshop scheduled for May 5, 2004.

Transmission constraints can impact the simultaneous deliverability of imports and internal generation. As a result, the interaction between the deliverability of imports and the deliverability of generation needs to be examined. The proposed generation deliverability assessment includes, as an input assumption, the amount of imports and existing transmission contract related encumbrances electrically flowing over the ISO Controlled Grid.

One of the observations from the Workshop was that LSEs needed to have results of the deliverability assessments in advance of submitting their resource plans to the CPUC for the year-ahead review. The generation deliverability assessment would provide results in advance. However, the deliverability of imports assessment initially described was an after-the-fact review of all of the LSE resource plans combined.

Because of the need for up-front information the ALJ assigned the ISO to lead a smaller group of Workshop participants to develop a methodology for determining the total amount of import capacity, by import path, which could be available to LSEs.[1] This document describes a proposal for a methodology developed by the subgroup.

Discussion of Proposed Approach

Whatever import capacity is available to LSEs for resource adequacy planning purposes should also be the basis for the import assumptions in the internal generation deliverability analysis. Because of the interaction between the deliverability of imports and the deliverability of internal generation, one should not simply determine the maximum import capability under favorable conditions and make that import capability available to LSEs for developing their resource plans. This approach assumes that all the import capability is needed and will be used for resource

[1] Determining a methodology for allocating import capability to LSEs was not an assignment of this working group.

APPENDIX E

Assessment of Total Import Capacity
Deliverability Proposal discussed in the Workshops. This benchmarking analysis would establish the deliverability of internal generation.

Per the ISO's Compliance filing for FERC Order 2003, the procedures for interconnection of new generators to the ISO controlled grid includes a Deliverability Assessment as part of the required technical studies. This assessment on new generators would be performed using the same methodology described in the Strawperson Proposal. The deliverability of existing generation already determined to be deliverable in the baseline deliverability analysis would be preserved. Once the new generator's deliverability level is established, its deliverability would be maintained as well.

The deliverability of new firm import contracts that utilize transmission import capacity allocated or acquired through trade by an LSE also would be maintained. These contracts would be modeled in future baseline deliverability studies. New firm import capacity could be identified in future baseline studies and allocated to LSEs for their use.

Generation retirements would be modeled and the deliverability impact on existing internal generators and imports would be included in the results of the baseline deliverability studies.

Deliverability Priority
If the baseline deliverability analysis for existing generation determines that the initial import level assumption is reducing the deliverability of internal ISO grid generation, then the initial import levels will be reduced and the baseline deliverability analysis will be re-run. Although it is not anticipated that import levels will have to be reduced significantly from their initial level, this issue may need to be reassessed after the analysis is completed, consistent with the "Review of Results" paragraph (below.)

New resources that are determined to be deliverable in the interconnection process, either because there is adequate existing capacity or through the construction of network upgrades, should have equal priority with pre-existing deliverable resources.

Make Results of Deliverability Assessment Available for Use
Once the deliverability assessment is completed the results will be provided for use in developing year-ahead LSE resource procurement plans for resource adequacy purposes.[2] The total import capacity, by path, determined to be deliverable would need to be allocated to LSEs using some allocation methodology that has yet to be defined.

---

[2] Operational requirements of the various local areas (i.e., RMR areas) would need to be addressed so LSEs have the necessary information to develop their resource procurement plans. This includes operational requirements such as the amounts and locations of generation needed to be on line and the potential generation retirements that could increase local area requirements. The deliverability to load methodology should focus on these requirements.

DRAFT
April 30, 2004

Deliverability Workshop Follow-Up
Allocating Total Import Deliverability

Background

At the CPUC's April 12-13, 2004 Deliverability Workshop, the California ISO was requested to coordinate a detailed technical discussion and develop a proposal for establishing the total import capacity, for each import path, which would be allocated to Load Serving Entities (LSEs) for resource adequacy planning purposes. Three alternatives for allocating the total import deliverability were identified and discussed at the workshop:

1. Historical Rights Allocation Method
2. Pro Rata Allocation Method
3. Auction Method

The ISO's workshop assignment did not include coordinating the discussion on how to allocate the import deliverability. This document discusses the three allocation alternatives identified in the workshop and recommends adopting a hybrid of the Pro Rata Allocation Method and the Historical Rights Allocation Method--at least for the initial round of LSE resource procurement.

Historical Rights Allocation Method

The Historical Rights Allocation Method would allocate the deliverable capacity on each import path consistent with each LSE's historical rights to use that import path.

Some transmission ties were developed for the express purpose of importing specific resources, which the LSEs now depend on for their resource adequacy. The main advantage of the Historical Rights Allocation Method is that the resulting allocation would not conflict with any LSE's existing long-term commitment to an external resource.

Some of the disadvantages of the historical rights allocation method include the following:

- There may be disagreements on what constitutes a valid historical right, such as when an agreement that grants such rights terminates.
- It does not consider what import deliverability each LSE needs for its present resource procurement effort.
- It does not give LSEs with low historical import rights the chance to increase their rights, even if the other LSEs with historical rights no longer have a need for some of those rights.
- The resulting allocation has no relation to the size of an LSE's load or how much an LSE pays for transmission access.

In short, the Historical Rights Allocation Method is likely to unfairly endow a minority of the LSEs.

Pro Rata Allocation Method

The Pro Rata Allocation Method would allocate the deliverable capacity on each import path to each LSE that pays the applicable High Voltage Access Charge (HVAC) or Low Voltage Access Charge (LVAC) for that path in proportion to the LSE's load that is included in the billing determinant for that Access Charge. A pro rata share of the deliverable capacity of each High Voltage (i.e., above 200 kV) import tie would be allocated to each LSE that pays the HVAC. A pro rata share of the deliverable capacity of each Low Voltage tie would be allocated to each LSE that pays the Access Charge (which presently is the LVAC of the owning PTO) applicable to that tie.

DRAFT

April 30, 2004

Step 4: Each LSE will use its allocation of import deliverability in conjunction with its resource portfolio to make the required demonstration of its resource adequacy. Any portion of the import deliverability allocation that is not needed for such demonstration would be released on a pro rata basis to the other LSEs that both requested it in Step 3 and then use it to make the required demonstration of its resource adequacy. To the extent no other LSE requests and uses the surplus import deliverability allocations in accordance with this Step 4, the LSE will retain its surplus import deliverability allocations and may use them to support resource procurement until the next import deliverability allocation cycle.

Step 5: In subsequent years, when import deliverability is allocated, an LSE will retain any portion of its previous import deliverability allocation as long as it is needed to count an external resource that it already owns or has under contract toward meeting its resource adequacy requirement. Such allocations will be accounted for in step 2a of future import deliverability allocations using this process. Once an LSE's contract or ownership for an external resource terminates, continued use of its import deliverability allocation for that resource received in Step 2a would become subject to a right of first refusal by the other LSEs that originally received the allocation in Step 1 and then lost it in Step 2b.

Relationship to CRRs

The CAISO is now in the process of determining how Congestion Revenue Rights (CRRs) will be allocated. In addition, there also is an existing process for auctioning Firm Transmission Rights (FTRs). CRRs (which will replace FTRs) provide their holders financial protection from congestion charges. But, they are not necessary to assure the physical ability to import a resource. As long as these deliverability and counting processes allow the sum of all LSE external resources to count only up to the import capability of the transmission, and no more, then adequacy should be assured. Costs of congestion (or excess demand on import capability) does not effect the LSEs resource adequacy, and when congestion is occurring, the ISO would still be getting physical imports into the area equivalent to the counted capability regardless of excess demand to use the import ties. Therefore, possession of CRRs or FTRs should not be a requirement for counting an external resource as deliverable.

Recommendation

The Hybrid Method described above has all of the advantages and avoids all of the problems of the Historical Rights Allocation Method and the Pro Rata Allocation Method. It also is much less complex than the Auction Method, and its outcome is much more likely to avoid unintended consequences. For these reasons, <u>the Hybrid Method for allocating import deliverability is recommended</u>.

APPENDIX G: Percent Variation From Peak

Percent Variation from Peak

2003			2002			2001			2000 (see note)			1999			1998 (see note)		
	MW	% Max		MW	% Max		MW	% Max		MW	% Max		MW	% Max		MW	% Max
1	42,689	0.00%	1	42,441	0.00%	1	41,419	0.00%	1	43,360	0.00%	1	45,884	0.00%	1	44659.12	0.00%
2	42,584	0.25%	2	42,366	0.17%	2	41,392	0.07%	2	43,234	0.29%	2	45,705	0.39%	2	44657.22	0.00%
3	42,539	0.35%	3	41,626	1.92%	3	41,186	0.56%	3	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
4	41,975	1.67%	4	41,385	2.49%	4	40,699	1.74%	4	42,762	1.38%	4	45,449	0.95%	4	44231.65	0.96%
5	41,734	2.24%	5	40,820	3.82%	5	39,805	3.90%	5	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
6	40,664	4.74%	6	40,246	5.17%	6	39,669	4.23%	6	41,322	4.70%	6	44,196	3.68%	6	42955.41	3.81%
7	40,653	4.77%	7	40,232	5.20%	7	38,375	7.35%	7	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
8	39,236	8.09%	8	39,067	7.95%	8	38,148	7.90%	8	39,527	8.84%	8	42,831	6.65%	8	41313.95	7.49%
9	39,064	8.49%	9	38,824	8.52%	9	37,720	8.93%	9	39,019	10.01%	9	42,496	7.38%	9	40749.32	8.75%
10	38,149	10.64%	10	38,597	9.06%	10	37,001	10.67%	10	38,696	10.76%	10	41,423	9.72%	10	40404.74	9.53%
11	38,144	10.65%	11	38,382	9.56%	11	36,743	11.29%	11	38,176	11.96%	11	41,040	10.56%	11	39500.91	11.55%
12	37,793	11.47%	12	37,829	10.86%	12	35,428	14.46%	12	37,489	13.54%	12	40,831	11.01%	12	39147.90	12.34%
13	36,004	15.66%	13	36,111	14.91%	13	33,899	18.16%	13	36,108	16.72%	13	39,058	14.88%	13	37022.03	17.10%
14	34,735	18.63%	14	35,716	15.84%	14	33,482	19.16%	14	34,190	21.15%	14	37,797	17.62%	14	36122.10	19.12%
15	33,287	22.03%	15	33,935	20.04%	15	31,442	24.09%	15	34,024	21.53%	15	36,102	21.32%	15	34197.61	23.43%
16	30,863	27.70%	16	32,443	23.56%	16	30,093	27.35%	16	31,285	27.85%	16	33,739	26.47%	16	31800.21	28.79%
17	30,530	28.48%	17	31,228	26.42%	17	29,196	29.51%	17	30,289	30.14%	17	32,926	28.24%	17	31362.66	29.77%
18	28,207	33.93%	18	28,312	33.29%	18	27,006	34.80%	18	28,324	34.68%	18	29,258	36.23%	18	28576.33	36.01%
19	26,481	37.97%	19	28,076	33.85%	19	26,422	36.21%	19	28,106	35.18%	19	27,052	41.04%	19	27936.62	37.44%
20	25,660	39.89%	20	26,546	37.45%	20	25,545	38.32%	20	26,312	39.32%	20	25,808	43.75%	20	25942.81	41.91%
21	25,154	41.08%	21	25,841	39.11%	21	25,017	39.60%	21	26,177	39.63%	21	25,385	44.68%	21	25637.77	42.59%
22	23,942	43.92%	22	25,363	40.24%	22	24,071	41.88%	22	24,868	42.65%	22	24,261	47.13%	22	24306.13	45.57%
23	23,921	43.97%	23	25,009	41.07%	23	23,898	42.30%	23	24,257	44.06%	23	24,214	47.23%	23	23955.44	46.36%
24	23,432	45.11%	24	24,736	41.72%	24	23,371	43.57%	24	23,897	44.89%	24	23,660	48.43%	24	23683.85	46.97%

*peak load day 8/16 was disrupted by interruptions analysis on second highest peak day 8/17/2000

*peak load day 8/31 was disrupted by interruptions, analysis on second highest peak day 8/12/1998

		Estimated MWs on 45,000 day
2 Hour average:	0.89%	401.26
4 Hour average:	2.69%	1209.15
6 Hour average:	5.25%	2361.66

(End of Attachment A)